The geological risks of exploring for a CO 2 storage reservoir

Citation for published version:
Xia, C & Wilkinson, M 2017, 'The geological risks of exploring for a CO 2 storage reservoir', *International Journal of Greenhouse Gas Control*, vol. 63, pp. 272-280. https://doi.org/10.1016/j.ijggc.2017.05.016

Digital Object Identifier (DOI):
10.1016/j.ijggc.2017.05.016

Link:
Link to publication record in Edinburgh Research Explorer

Document Version:
Peer reviewed version

Published In:
International Journal of Greenhouse Gas Control

The geological risks of exploring for a CO_2 storage reservoir

Changyou Xia, Mark Wilkinson

School of GeoSciences, Grant Institute, the King's Buildings, James Hutton Road, Edinburgh, EH9 3FE, UK

Corresponding author: Mark Wilkinson, mark.wilkinson@ed.ac.uk

Keywords: drilling, exploration, risk, storage, North Sea

Abstract

Experience of developing saline aquifers as CO_2 storage sites is limited. Drawing on the experience of hydrocarbon exploration, there are geological risks that may be encountered during the search for CO_2 storage sites, such as finding a reservoir of insufficient thickness, of low porosity or lacking an adequate seal. We use drilling records of 382 hydrocarbon boreholes on the UK Continental Shelf to analyse the geological risks of exploring for a new CO_2 storage reservoir, on the assumption that the probability of occurrence of geological risks are similar. The most significant risks for a new borehole are the absence of the target reservoir (19 ± 3 % of cases), low reservoir quality (16 ± 5 %) and lack of trap (16 ± 3 %). Overall, 48 ± 8 % of subsurface structures, identified from seismic data, can potentially store CO_2. For saline aquifers that have already been penetrated by wells within the potential storage site, most of the geological risks are eliminated or at least reduced; reservoir compartmentalization is the major remaining geological risk. This study demonstrates a method to quantitatively apply drilling data from hydrocarbon exploration to the exploration for CO_2 storage reservoirs in analogous geological settings.

1. Introduction

One of the challenges of developing saline aquifers as CO_2 storage sites is the lack of pre-existing geological data, in contrast to developing storage in a depleted hydrocarbon field where legacy data should be available. A potential risk is hence drilling a target aquifer, and discovering, for example, that the expected reservoir unit is absent, or is of too low porosity to be useable. This is a surprisingly common result for hydrocarbon exploration wells, even when drilling in areas with relatively well-known geology such as the UK Continental Shelf (UKCS). Because CO_2 geological storage is a field with limited practical experience, in this study we use historical drilling records for hydrocarbon exploration on the UKCS to estimate the probability of finding a useable CO_2 storage site upon drilling a single borehole.

A borehole drilled in the exploration for conventional hydrocarbons can be unsuccessful because of an absence of any of the components of the conventional petroleum system: source, migration, reservoir, trap, seal and preservation. If any of these essential elements are absent, then a borehole will be unsuccessful – here we term these essential elements to be 'risk factors'. Potential CO_2 stores only require three of these fundamental elements: reservoir, seal and trap, and accordingly have 3 risk factors, or more correctly groups of risk factors as each can be subdivided (Table 1). The probability of finding an effective CO_2 storage reservoir (probability of success, POS) can be estimated by deriving the probability of an exploration borehole encountering a reservoir with integral reservoir, seal and trap (Equation 1).

POS = P (reservoir success) × P (seal success) × P (trap success) **Equation 1.**

The UKCS is an unusual hydrocarbon province in world terms due to the unusually wide stratigraphic distribution of hydrocarbon resources (Brennand et al., 1998). Commercially viable hydrocarbon reserves have been found in reservoirs of Paleogene, Cretaceous, Jurassic, Triassic, Permian and Carboniferous ages (Eriksen et al., 2003). Reservoirs were deposited in a wide range of sedimentary environments, and have had burial histories that vary from almost continuous burial to multiple periods of basin inversion. This study estimates the probability of success of locating storage sites for CO_2 in reservoirs of varying ages and sedimentary environments on the UKCS by using historical drilling for hydrocarbons as an analogue. Note that only geological factors are considered, and not technical drilling issues which may result in the loss of the borehole, for example a stuck drill bit.

2. Methods

The reasons for oil exploration boreholes being deemed unsuccessful have been collated from relinquishment reports of UK offshore exploration licences, i.e. reports written by hydrocarbon companies for the UK Government at the expiry of a petroleum exploration licence. The data were collected from 651 relinquishment reports of exploration licenses on the UK Oil & Gas Authority website (https://itportal.decc.gov.uk/web_files/relinqs/relinqs.htm). The database compiled for this study contains 348 unsuccessful wells. About 85% of the wells are exploration wells and the remainder are appraisal wells. Seven pieces of information for each unsuccessful well were recorded: well identification number; target formation name; sedimentary facies of the target reservoir; trap type; geographical location; any hydrocarbon shows and the reason(s) why the borehole was deemed to be unsuccessful (Supplementary data Table S1).

In order to estimate the probability of success (POS) of drilling a successful borehole, the number of occurrences of each geological risk among the unsuccessful wells has been tabulated, which is here referred to as the frequency. For every well, each significant geological factor that caused the borehole to be unsuccessful is counted as 1 count. Some wells may have 2 or 3 listed reasons for being unsuccessful. All the critical risks that could prevent a borehole being successful were counted. For example, if a well is unsuccessful due to both low reservoir permeability and a lack of hydrocarbon charge, each of the two reasons are counted as 1 because either one of them would cause the borehole to be unsuccessful. There is no relative weighting of the risk categories, i.e. each geological risk category is treated as being equally important, as failure in any category would cause the search for a CO_2 storage site to be unsuccessful. When a borehole has multiple reservoir targets, only the main target is counted. One common situation is that a borehole was found to be dry but it was unknown whether this is due to a lack of charge or lack of seal. In this circumstance, both the risks of charge and seal are counted as 0.5. From the tabulated data, the occurrence of a specific geological risk factor in unsuccessful wells is calculated as a proportion of the total number of unsuccessful wells.

The probability of occurrence (P_{risk}) of each geological risk factor in all wells (i.e. both successful and unsuccessful), is estimated from Eqn. 2.

P_{risk} = frequency/ (Σ unsuccessful wells + Σ successful wells) **Equation 2**

The overall success rate of exploration wells in the North Sea over time is around 30% (Brzozowska et al., 2003; Munns et al., 2005; Ofstad et al., 2000). For a CO_2 storage reservoir to be effective, all the geological risks must be avoided. The probability of avoiding each risk factor, assuming a probability of success for all exploration wells of 30 %, is hence:

$P_{avoid} = 1 - P_{risk}$ **Equation 3**

Hence, the overall probability of a borehole finding an effective CO_2 storage location (POS) can be estimated from Eqn. 4, which is an expanded version of Eqn. 1.

POS = P_{avoid} (reservoir presence) × P_{avoid} (reservoir quality) × P_{avoid} (reservoir non-compartmentalised) × P_{avoid} (reservoir lateral certainty) × P_{avoid} (trap geometry) × P_{avoid} (trap at prognosed depth) × P_{avoid} (caprock seal) × P_{avoid} (fault seal)* × P_{avoid} (lateral / bottom seal)**

(*only for fault-bounding traps; ** only for stratigraphic traps) **Equation 4**

The results are subject to uncertainty. On the assumption that the occurrences of the identified risks are mutually independent, i.e. the occurrence of one risk does not affect the occurrence of the others then the probability distribution follows a binomial distribution pattern. Confidence interval of a binomial distribution are determined by Eqn. 5 (Wallis, 2013) where p = probability; n = number of trials. Results are here presented at the 90% confidence interval, and hence the value of z is 1.645.

$$\text{Uncertainty} = \boldsymbol{z} \times \frac{\sqrt{\boldsymbol{1-p}}}{\sqrt{\boldsymbol{np}}} \qquad \textbf{Equation 5}$$

3. Results

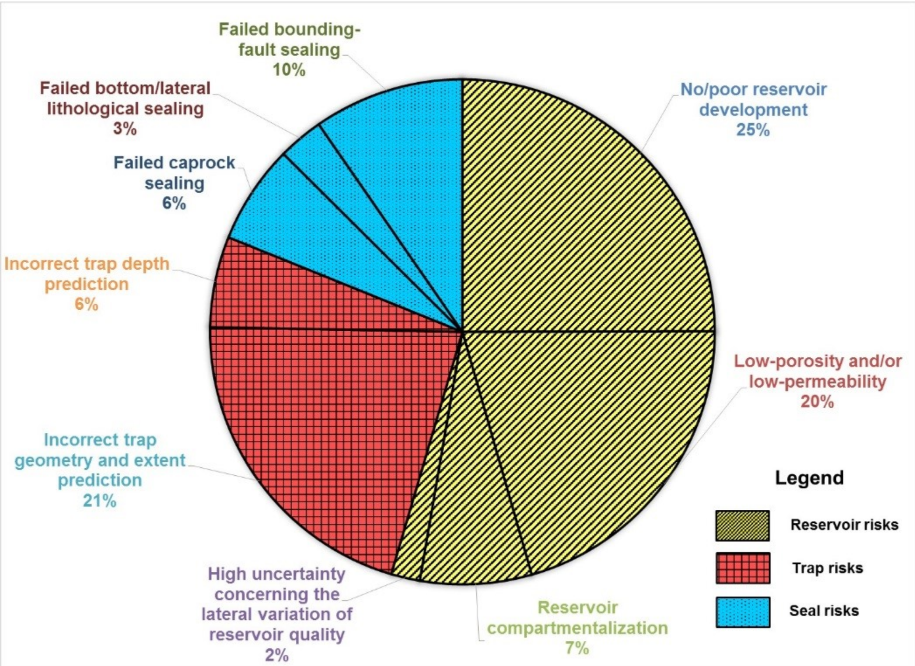

Fig. 1. The geological reasons for the failure of boreholes to locate commercial hydrocarbon accumulations in the UKCS.

The most prevalent geological risks in the UK offshore hydrocarbon exploration are encountering reservoirs that are less than the prognosed thickness or are absent; of low reservoir quality; and having an incorrectly defined trap (Fig. 1; Table 1). The reported causes of the risk factors are listed in Table 2. The trap type of reservoirs in the UKCS can be classified as: periclinal traps, fault-bounding traps and stratigraphic traps (including stratigraphic-structural combination traps). Around 30% of the reservoirs studied are within periclinal traps (Table 3). Nearly half are within traps that are bounded by one or several faults. The remainder are in traps that have an element of stratigraphic trapping (Table 3). The risk of reservoir seals have been analysed according to the types of traps.

The probability of a reservoir having a successful caprock seal, regardless of trap type, is estimated to be 95 ± 2 % (Table 1). For fault-bounding traps, the probability of having sealed faults is slightly lower at 82 ± 4 % (Table 3). However, this does not mean that 82 % of subsurface faults are sealed. but that 82 % of pre-drill fault analyses, which concluded that faults were likely to be sealed, were correct – if a pre-drill seal analysis suggested probable failure, then a borehole would not have been drilled. The critical factor for stratigraphic seals is the bottom or lateral seal (74 ± 10 % probability of success) which is slightly higher risk than fault seals, which is consistent with experience within the hydrocarbon industry that stratigraphic traps inherently have higher risk seals than periclinal or fault-bounding traps (Downey, 1984). The risks of reservoir compartmentalization, incorrect trap depth prediction and failed caprock sealing are at the similar level, each of them occurs approximately once in 20 boreholes (Table 1). Their reported causes are summarised in Table 2.

The probability of not encountering geological risks in a borehole, i.e. the probability of success for each risk factor are in Fig. 2. The geological risks of the main reservoir units of different age in the UKCS are in Table 4, and the probability of success of a borehole, categorised by the stratigraphic age of the target reservoir, is given in Table 5 and Fig. 3.

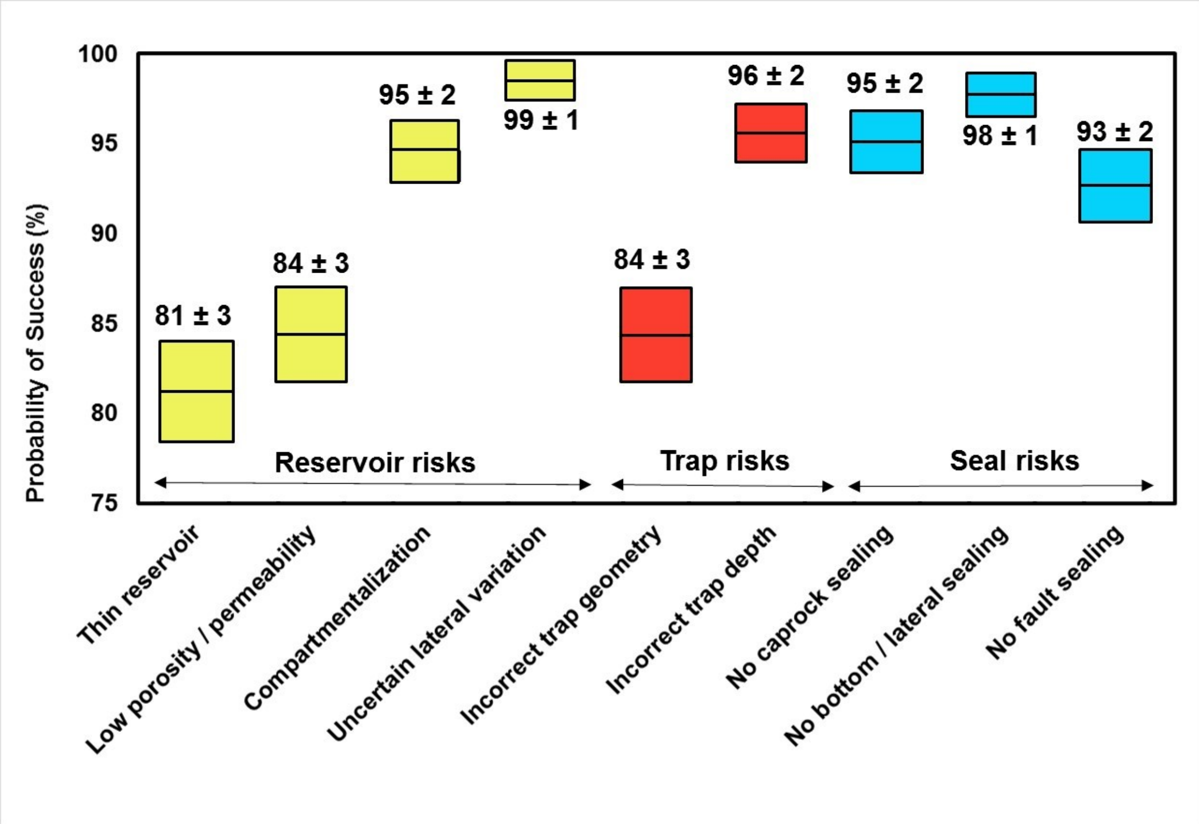

Fig. 2. The probability of not encountering geological risks (Pavoid)ina borehole, i.e. the probability of success for each risk category.

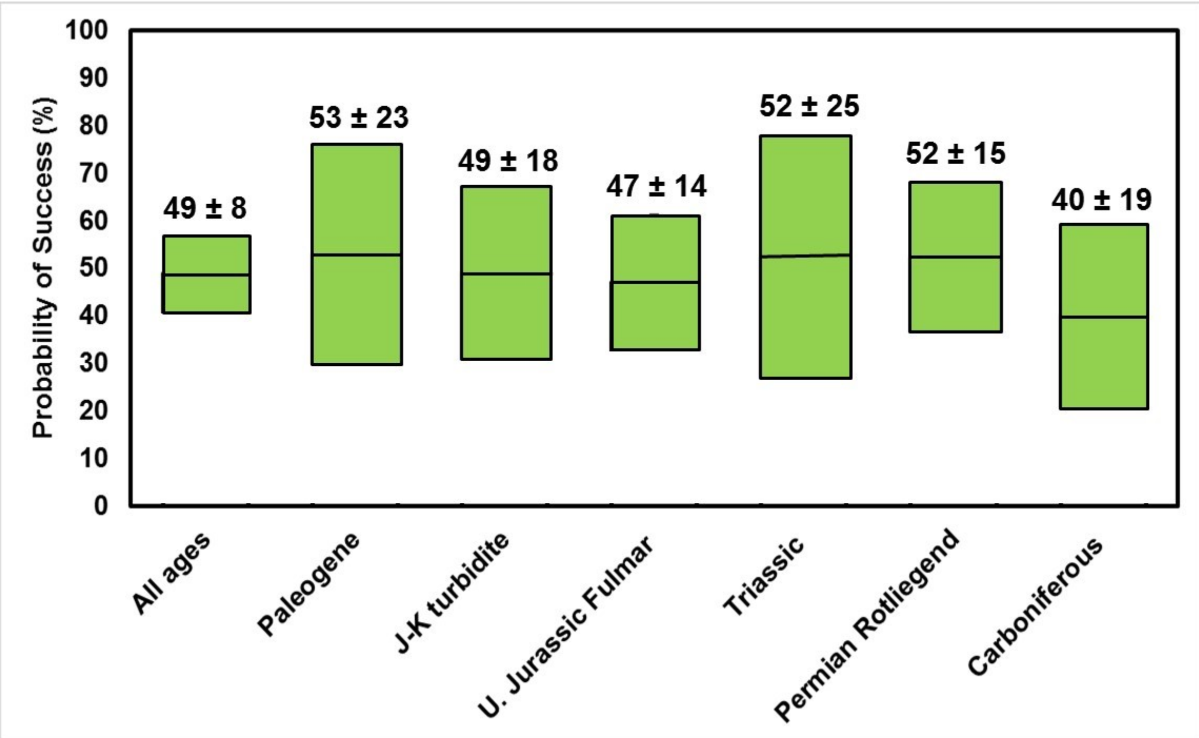

Fig. 3. The probability of success of a borehole by age of the reservoir (periclinal traps only). J-K is Jurassic-Cretaceous.

4. Discussion

The most important risk factors for a new borehole drilled for CO_2 storage, as indicated by experience of drilling for hydrocarbons, are reservoir presence; reservoir quality; and trap definition (Table 1). Absent, thin or low-porosity target reservoirs could cause a CO_2 storage project to fail after the drilling of a first well, at considerable expense. Incorrect trap definition could lead to erroneous estimates of storage volume or a failure to trap CO_2 in the target structure, leading ultimately to leakage.

4.1. Risk of reservoir absence or being too thin

From the hydrocarbon drilling records, 27 ± 4 % of the unsuccessful exploration wells have reservoirs whose thicknesses do not meet the pre-drill expectations (Table 1). Assuming the overall success rate of hydrocarbon exploration wells is 30% (as above), it suggests that 81 ± 3 % of CO_2 storage wells will find the target reservoir to be satisfactory (Table 1). For a borehole drilled into a saline aquifers with few existing wells, there is hence a significant risk (approximately 1 in 5) that the target reservoirs will be absent or too thin. The risk of reservoir absence is highest among shallow marine sandstone, and decreases through turbidite sandstones and fluvial-deltaic sandstones, to aeolian sandstones (Table 4). Hence, the depositional environment of the reservoir determines the risk of reservoir absence, presumably by controlling geometry especially lateral continuity.

4.2. Risks associated with poor reservoir quality

The chance of encountering a target reservoir with adequate porosity and permeability for CO_2 injection and storage is estimated at 84 ± 3% (Table 1). Storing CO_2 in a low-porosity, low-permeability reservoir is costly and technically challenging. The In Salah project is a case in point where the reservoir has 10-15% porosity and 1-50 mD permeability (Eiken et al., 2011). To improve the injectivity of the reservoirs, three horizontal injection wells were drilled, at considerably higher cost than vertical wells (Ringrose et al., 2013). If large number of saline aquifers are to be drilled for CO_2 storage in future, it is highly likely that some of them may encounter the problem of poor reservoir quality. However, the depth of burial for the majority of CO_2 storage reservoirs in future are expected to be in the range of 1 – 3 km, compared to the common depth of 2 – 6 km for the oil and gas fields on the UKCS. As depth is a strong control upon the porosity of sandstone reservoirs, an important question is whether the probability of encountering a low-porosity hydrocarbon reservoir is a good analogue for the CO_2 storage case. But one complicating factor for hydrocarbon reservoirs is the filling of hydrocarbons, which has been suggested to preserve porosity by halting or retarding quartz cementation (Wilkinson and Haszeldine, 2011; Worden et al., 1998). This is shown by higher porosity in oil-bearing sections than the water-bearing equivalents in many oilfields (e.g. Marchand et al., 2000). It is here considered that the effect of relatively shallow burial depth for CO_2 storage will at least partly offset the need for better reservoir quality, and the lack of porosity preservation by hydrocarbon charge in an aquifer. Thus, we believe the probability of encountering a low porosity hydrocarbon reservoir can still be applied to estimate the probability of drilling into a low porosity aquifer sandstone, though with a degree of caution.

4.3. Risks associated with poor trap definition

A good evaluation of a trap requires its depth, relief, lowest-closing contour and geometry to be correctly described. Precise definition of traps is also required to quantify the storage capacity of a CO_2 storage site, and to predict the unwanted lateral migration of CO_2. The inherent uncertainty in defining tarps is determined by a combination of several factors, including reservoir depth, reservoir geometry, the lithology of reservoirs and their neighbouring units, geological background of basins and quality of seismic data. For reservoirs of different depths, sedimentary environments and tectonic histories, the cause of the risk of trap definition can be very different. This section focuses on Palaeogene and Cretaceous turbidite reservoirs in Central and Northern North Sea, and the Triassic - Permian reservoirs in the Southern North

Sea, both of which have substantial potential for CO_2 storage (Heinemann et al., 2012; Senior, 2010).

The probability of correctly defining the trap geometry of Paleogene reservoirs is estimated to be 85 ± 9 % (Table 4), hence there is a 15 ± 9 % probability that the trap will not be adequate. However, the risk of trap definition for Palaeogene targets has been estimated to be substantially higher in some other studies. For example, Loizou (2014) suggested that 80% of the unsuccessful wells in the Faroe-Shetland Basin are due to trap definition. This may be because the vast majority of exploration targets in the area are stratigraphic traps, where the definition of trap geometry is more challenging than conventional structural traps. This study, however, includes only 7 wells from the Faroe-Shetland Basin. Most of the study wells are from the Central and Northern North Sea, where many of the Paleogene targets are periclinal traps, such as in the Forties, Montrose and Frigg Fields. Definition of periclinal traps in most cases is not problematic and therefore the overall risk associated with trap definition for Paleogene targets in the North Sea is not as high as only for the Paleogene targets in the Faroe-Shetland Basin. One factor that makes trap definition of turbidite sandstone targets difficult are their small thicknesses, which are often below seismic resolution (Chopra et al., 2006).

Traps in the Southern North Sea have problems of definition that are not found in the Central and Northern North Sea. The Southern North Sea has undergone multiple periods of inversion with regional uplift and erosion from Cretaceous to Neogene (Glennie and Underhill, 1998). As a result, the basin has been uplifted by up to 1 km (Glennie, 1998). Many sedimentary rocks in the Southern North Sea are now more compacted than would be anticipated for their current depth of burial and therefore have higher seismic velocity than expected (Glennie, 1998). Moreover, as the degree of the inversion is uneven across the basin, so the seismic velocity is highly variable both vertically and laterally. To construct an accurate seismic velocity model and conduct accurate time-depth conversion is therefore very difficult in many areas. Hence, it is common to have high uncertainties in depth prognoses for Southern North Sea drilling targets, and these uncertainties must be thoroughly considered and assessed during the selection of a CO_2 storage site.

4.4. Risks factors associated with the seals

In traditional petroleum geology, seals have been neglected compared to reservoir rocks (Downey, 1984). In the field of CO_2 storage, in clear contrast, studying and assessing reservoir seals have been the aim of considerable research effort (e.g. Busch et al., 2010; Lu et al., 2009; Wilkinson et al., 2014). The important properties of seals, for hydrocarbon reservoirs or CO_2 storage, are thickness, lateral variation, capillary entry pressure and degree of fracturing (Downey, 1984). Therefore, the probabilities of sealing success for hydrocarbon reservoirs and aquifer reservoirs can be seen as equivalent. However injecting CO_2 will increase reservoir pressure and therefore impose additional risks on the seals, at least locally. It is possible that the increased pressure can create or re-open fractures in seal rocks, or that the buoyancy of a CO_2 column breaches seal rocks (Busch et al., 2010). Furthermore, the CO_2 can potentially react with some of the minerals in the seal rocks, increasing the risk of leakage if flow paths are created (Smith et al., 2013). From the above, it is concluded that the risk associated with seal quality is higher for CO_2 reservoirs than for hydrocarbon fields.

4.5. Analysis of risk factors by stratigraphy

The UKCS includes important turbidite reservoirs of Palaeogene, Cretaceous and Jurassic age. For these reservoirs, the most significant risks are reservoir presence and definition of trap geometry (Table 4). The Palaeogene turbidite reservoirs in most cases are of high porosity and permeability, whereas the reservoir quality of the Cretaceous-Jurassic turbidites is usually lower as a result of deeper burial and a longer time for diagenesis to occur. In contrast, caprocks of the Cretaceous-Jurassic turbidite reservoirs appear to have better sealing abilities than those of their Paleogene counterparts, possibly because the older caprocks are compacted and lithified at a higher degree.

The Upper Jurassic shallow marine sandstones of the Fulmar Formation are the most important hydrocarbon reservoirs in the Central North Sea (Eriksen et al., 2003). They are a highly homogeneous sandstone of substantial thickness, commonly in the range of 100-350m (Richards et al., 1993). However, the potential of the Fulmar Formation as a CO_2 storage target is restricted by the fact that large parts of the Fulmar Formation are overpressured, limiting the permissible pressure increase before rock failure (Holloway et al., 2006b). A small fraction of the Fulmar Formation aquifers in the marginal areas of the Central North Sea, which are at shallow depths and are not overpressured, might be suitable for CO_2 storage. The most significant risk for shallow marine sandstone reservoirs, as represented by the Fulmar Formation, is a thin or absent reservoir. Nearly half of the unsuccessful Fulmar wells are caused by this issue (Table 4). The Fulmar Formation was not deposited as a single laterally continuous sand body, but rather as a complex pattern of elongate and narrow belts bounded by a series of graben faults (Howell et al., 1996). Distribution of the sand was controlled by a combination of sea level change, fault movements and halokenesis (Howell et al., 1996; Stewart, 1986). A favourable aspect of the Fulmar Formation as a storage reservoir is that it has been intensively drilled and studied due to its importance to the oil and gas industry. With the abundance of control wells, the geological risks of using the Fulmar Formation for CO_2 storage may be easier to manage than for some of the other formations.

The dataset of Triassic reservoirs is small since they only contain minor hydrocarbon reserves in the UKCS (Table 4). The most frequent reason for the failure of boreholes targeting the Triassic is incorrect prediction of trap geometry (9 wells). Notably 6 of these wells are located in the Irish Sea, indicating that trap definition is a high risk for the Triassic gas reservoirs there. The causes of the difficulties in the trap definition for Triassic reservoirs however are diverse: of the 9 wells, three are stated to be unsuccessful due to the unexpected presence of salt in the overburden; one due to the unexpected presence of volcanics in the overburden; one due to higher than expected chalk velocity; and one is due to an unspecified problem with the velocity model (Supplementary data). Specific failure reasons for the remaining three wells are not given in the reports.

The Rotliegend Sandstone is the dominant reservoir rock in the Southern North Sea, holding over 80% of gas reserves of the area (Gray, 2013). Reservoir quality is identified to be the most significant risk for Rotliegend reservoirs (Table 4). The obstacle for accurately predicting the porosity of Rotliegend Sandstone is the lack of clear relationship between the porosity and the sedimentary facies and current burial depth of the sandstones. The Southern North Sea basin has a more complex history than the Central and Northern North Sea. It has been uplifted and subjected to erosion during Cretaceous and Tertiary, and as a result many of the Rotliegend sandstones are currently up to 1km shallower than their maximum depth of burial in history (Glennie, 1997). Current burial depth is hence not a reliable indicator of porosity prediction of many Rotliegend sandstones. A well-known problem in the Rotliegend Sandstone reservoirs is compartmentalization by faults (e.g. Leveille et al., 1997; Van Hulten, 2010), however only one Rotliegend well in this study was described as unsuccessful due to reservoir compartmentalization (Table 4). This may be because reservoir compartmentalization is usually not obvious in the reservoir exploration and early appraisal phase (Van Hulten, 2010). For instance, compartmentalization was not seen as a reservoir issue in the primary field development plan of the Groningen field, the largest gas field in the Europe (Udink, 1968). Only after several years of production was gas flow was found to be determined by sealing faults (Van Rossum, 1975).

Exploration for Carboniferous reservoirs has similar difficulties to the Rotliegend reservoirs described above (Table 4). At least in the Southern North Sea, these two sets of reservoirs have been uplifted and buried together for the majority of their geological history. For the same reason as the Rotliegend Sandstone, the greatest challenge for the exploration of Carboniferous reservoirs is to successfully predict the presence of moderate or high porosity sandstone (Table 4). In addition, reservoirs in the Southern North Sea, including both the Carboniferous and Rotliegend reservoirs, all face a high risk of trap definition (Table 4). This is due to the complexity in the overburden geology above the reservoirs caused by basin inversions and salt tectonics (Besly, 1998). The situation is more difficult for the Carboniferous reservoirs, as their definitions on seismic images are further impeded by the small thickness of the sandstones and by the lack of acoustic impedance contrast between the Carboniferous and Rotliegend sequences (Besly, 1998).

The POS of a borehole drilled into a Carboniferous reservoir target is lower than that of the other reservoirs though with considerable uncertainty (Table 5). This is mostly because of the poor reservoir quality of many Carboniferous reservoir rocks (Table 4). The advantage of Carboniferous reservoirs for CO_2 storage is their high quality seal; many are sealed by multiple layers of shales and evaporites (Besly, 1998). Top seal failure is rarely reported from Carboniferous reservoirs (Table 4). However, the small sizes of Carboniferous reservoirs in comparison to younger reservoirs (Gluyas and Hichens, 2003) may limit their utility as CO_2 storage reservoirs.

5. The probability of success (POS) for new CO_2 storage boreholes

Based on the geographical location of CO_2 storage sites relative to existing hydrocarbon fields, CO_2 storage saline aquifer reservoirs can be divided into two groups:

- Saline aquifers associated with a hydrocarbon field. These saline aquifers can be directly above the hydrocarbon reservoir of the field, such as the Utsira Formation of the Sleipner project; below the hydrocarbon reservoir, such as the Tubåen Formation of the Snøhvit project; or downdip of the hydrocarbon reservoir, such as the in the In Salah project (Cooper et al., 2009). These potential CO_2 storage sites are henceforth referred to as 'proven reservoirs'.
- Saline aquifers that are distant from hydrocarbon fields. These reservoirs are henceforth referred to as 'unproven reservoirs'.

The experience of hydrocarbon exploration is applicable to both unproven and proven reservoirs, but has to be applied differently.

5.1. The geological risks of an unproven storage site – implications for regional storage capacity assessments

An unproven reservoir for CO_2 storage can be treated as an undrilled hydrocarbon prospect, as the methods of subsurface characterization of hydrocarbon reservoirs and saline aquifers are essentially the same. The probability of encountering any given geological risk during hydrocarbon exploration can be used to predict that of the same geological risk in developing unproven aquifer reservoirs, and ultimately the associated POS.

The fact that drilling into known reservoir horizons, on identifiable structures, carries a significant risk that the site will be unsuitable for CO_2 storage (Table 5) has implications for regional assessments of CO_2 storage capacity. Currently, the vast majority of national/regional estimation of CO_2 storage capacity is only at a theoretical level (Bachu et al., 2007; Holloway et al., 2006b; Senior, 2010). All the subsurface formations that appear to be capable of storing CO_2 based on available information are considered over their known geographical extent (e.g. Heinemann et al., 2012; Holloway et al., 2006). However, by analogy with hydrocarbon exploration, not all the geographical extent of potential reservoir formations will have all the geological factors required to be effective CO_2 stores. Over a significant proportion of the mapped geographical range of a formation, there will be either no (or only a thin) reservoir; no seal; or individual traps may be incorrectly defined. To generate more reliable estimates of CO_2 storage capacity, it is important to understand what percentage of the subsurface might in fact be suitable for CO_2 storage.

In this study, the overall probability of success for aquifer reservoirs in periclinal traps is estimated to be 49 ± 8 % and fault-bounded traps to be an indistinguishable 45 ± 8 % (Table 3 & 5). Hence only approximately 1 in 2 CO_2 storage structures, which appear to be competent storage locations in a preliminary regional assessment, are expected to be successful. This suggests that the early stage estimates of CO_2 storage capacity in many studies need to be reduced by a factor of 2 to get a more realistic CO_2 storage capacity. The newly generated estimates by this method is approximately at the *effective* level, based on the classification pyramid of storage capacity in Bachu (2008). If financial and regulatory factors are also taken into consideration, these storage capacity estimates will be further reduced. The POS estimated for stratigraphic traps is 36 ± 10% (Table 3), suggesting that in an area where many of the traps have a stratigraphic component, early stage estimates of CO_2 storage capacity may need to be reduced by a factor of 3.

5.2. The geological risks of a proven reservoir

To apply the data presented here to estimate the POS of boreholes targeted at proven reservoirs is more problematic than the unproven reservoirs above. There are less uncertainties than for unproven reservoirs as once a well is drilled, many geological risks are reduced. Reservoir thickness and quality can be measured; reservoir pressure can be tested; the depth of the reservoir can be accurately determined. However, proven reservoirs still have only limited well coverage and there are three geological risks remaining that are subject to varying degrees of uncertainty: the degree of reservoir compartmentalization; the lateral variation in reservoir quality; and trap definition.

Reservoir compartmentalization is usually not apparent in the appraisal phase of a reservoir but gradually becomes evident in the operation phase as pressure and production data accumulate and can be compared with reservoir models (Jolley et al., 2010; Smalley et al., 1994). Understanding the degree and scale of reservoir compartmentalization is critical for CO_2 storage reservoirs, because it has a strong impact on the volume of reservoir available for CO_2 storage and for pressure dissipation. Furthermore, a compartmentalized reservoir may cause rapid pressure rise around injection wells and prevent further injection (Holloway et al., 2006).

The probability of encountering a reservoir with compartmentalization issues is here estimated as 5 ± 2 % (Table 1), however, this is only reservoirs which are characterised by a rapid pressure decline during well testing. As most hydrocarbon reservoirs have some degrees of compartmentalization (Smalley and Hale, 1996), there might be a larger number of reservoirs whose issues of compartmentalization have not been identified during initial well testing and are hence not reported in the relinquishment reports upon which this study is based. The actual number of compartmentalised reservoirs cannot be assessed in the present study. In total, there are 28 boreholes in this study that were abandoned due to the compartmentalization of target reservoirs. 13 of the boreholes were targeted on Jurassic reservoirs and in particular 6 of them are within the Fulmar Formation. The failures in the Fulmar Formation are mostly due to fractures or sub-seismic faults that are related to fault movement or Permian salt haloakinesis. Since there is are large number of wells targeted on the Fulmar Formation, this does not mean that the Fulmar Formation carries a higher risk of reservoir compartmentalization than other units. Another 9 wells were drilled into the Carboniferous reservoirs in the Southern North Sea. The Carboniferous reservoirs, however, do seem to have a high risk of being compartmentalized as there are not many Carboniferous wells but the number of failed boreholes is high (Table 4). Permeability heterogeneity due to facies variation because of the fluvial-deltaic depositional environment is reported to be the main cause of reservoir compartmentalization.

Although this study has not identified any compartmentalized reservoir in turbidite sandstones, the risk of compartmentalization must not be overlooked. Some Paleogene oilfields in UK water have a complex architecture, formed by turbidite channels, sheet turbidite sandstones and sealing faults (Jolley et al., 2010). Examples include the Schiehallion Field and Pierce Field (Gainski et al., 2010; Scott et al., 2010). In the Southern North Sea, it has been reported that the Triassic Bunter Sandstone aquifer is more suitable for CO_2 storage reservoir than the Permian Rotliegend Sandstone because it has less compartmentalization problems (Holloway et al., 2006). This is demonstrated by good pressure communication between the gas fields of the Bunter Sandstone (Holloway et al., 2006b). However, a lack of pressure barriers within a reservoir does not mean there are no baffles to fluid flow. The Bunter Sandstone was primarily deposited as a fluvial system, which may result in complex compartmentalization caused by overlapping and superimposed channels separated by non-reservoir overbank sediments (Ketter, 1991). There are only a limited number of gas fields within the Bunter Sandstone, which means the reservoirs of these fields may not be representative of the Bunter Sandstone as a whole. When characterising a 'proven structure' within the Bunter Sandstone, a careful assessment of reservoir compartmentalization is necessary.

6. Limitations and possible applications of the method

This study uses data from hydrocarbon exploration to estimate the risk of exploring for a new CO_2 storage reservoir. An important question is the validity of the analogy between hydrocarbon reservoirs and CO_2 storage reservoirs. The geological criteria for a successful hydrocarbon reservoir are not precisely the same as those for a successful storage reservoir, although both require competent reservoir, seal and (probably) a trap. In the previous sections, it has been suggested that the overall risks associated with the seal for CO_2 storage reservoirs are likely to be higher than for hydrocarbon reservoirs, whereas the risks associated with reservoir quality are considered to be comparable for the two. Regarding trap definition, saline aquifers will invariably lack any direct hydrocarbon indicators in seismic data, which, in some cases, assist in the definition of structures with trapped hydrocarbons. In these cases, the risk associated with trap definition for CO_2 storage in aquifers may exceed that for at least some hydrocarbon fields.

Another significant difference between the two kinds of reservoirs is their spatial scales. To store a volume of CO_2 that is significant for climate change mitigation, a large size of aquifer rather than a pilot site is required, whose areal extent can be several or tens of times larger than a regular hydrocarbon field. Over 70-80% of North Sea oil and gas fields are too small for commercial CO_2 storage, i.e. their storage capacity is less than 50 Mt of CO_2 (Holloway et al., 2006b). The larger areal size of CO_2 storage reservoirs, compared to the average size of hydrocarbon fields, could increase some of the geological risks of locating a suitable a reservoir. The risk of reservoir compartmentalisation, for example, may be higher for a large storage site simply because there is more probability of locating a sealing fault in a large area than in a smaller area. The risk of encountering lateral variation of seals or reservoirs is presumably also greater when a larger geographical area is being considered.

There is also the question of the overburden to the storage site, i.e. the stratigraphy between the top of the seal and the surface. In oil and gas exploration, this is of only secondary importance, while in CO_2 storage, it includes the location of any potential natural leakage pathways (faults, gas chimneys), and is also the 'seal of last resort' in the event of vertical leakage from the reservoir. At least part of the overburden is likely to be contained in the 'storage complex' – again providing a requirement for an understanding of the overburden which exceeds that required by hydrocarbon exploration. Whether any potential CO_2 storage site will, in the future, be rejected on grounds of unsuitable overburden geology remains to be seen, but it should be noted that overburden geology adds to the geological risks of searching for a CO_2 storage site. Other aspects in which hydrocarbon and CO_2 storage reservoirs have differing criteria include the cut-off limit of reservoir permeability, and the tolerance of the reservoir rocks to variations in pressure. For the former, gas can be produced at commercial rates from reservoirs with permeabilities that would be prohibitively low for CO_2 injection; compare 1-50 mD permeability in the commercially viable In Salah gas field (Eiken et al., 2011) with a minimum permeability of 200 mD, and a desired 500 mD, suggested for CO_2 storage by Chadwick et al. (2008). From the above, it might be concluded that the geological criteria for a successful CO_2 storage reservoir are more rigorous than those for a hydrocarbon reservoir, and hence that the probability of success of a borehole, drilled to locate a CO_2 storage site, might be rather less than for a hydrocarbon exploration borehole drilled in a geologically comparable area. This may be partly countered by the generally shallower burial depth of CO_2 storage compared to hydrocarbon exploration in the UKCS, the influence of which upon reservoir quality was discussed in Section 4.2.

The results of this study are based upon data from the UKCS, and the results are hence most directly applicable to the search for CO_2 storage reservoirs in this geographical area. Caution must be exercised in applying the conclusions to other geographical areas, and judgement must be applied as to how comparable, from a geological perspective, an area is to the UKCS. In a rift basin with comparable age sediments, at comparable burial depths, then confidence may be quite high. However, for a better understanding of the geological risks of exploring for CO_2 storage sites worldwide, it would be useful to undertake comparable studies using legacy exploration data from other hydrocarbon provinces, especially those with a high likelihood of being used for CO_2 storage.

Conclusions

1. On the assumption that past drilling for hydrocarbons on the UKCS provides a good analogue for drilling for a CO_2 storage site, then for a subsurface location with limited geological information, the probability of a borehole encountering a reservoir suitable for CO_2 storage is only c. 41 – 57 % (P10 to P90), despite the well-known geology of the area. This has implications for regional assessments of CO_2 storage capacity.
2. For reservoirs with stratigraphic traps within the UKCS, the probability of success is slightly lower, at 36 ± 10%.
3. The most frequent reasons for boreholes being unsuccessful on the UKCS are a lack of (or thin) reservoir; poor reservoir quality and the lack of a trap, all of which factors that are important for CO_2 storage sites.

4. The major geological risk varies with sedimentary environment, stratigraphy and reservoir age. For Paleogene, Cretaceous and Jurassic turbidite reservoirs the main risk is the lack of a trap. For Upper Jurassic shallow marine sandstones, the major risk is the absence of the reservoir. For Permian Rotliegend and Carboniferous reservoirs, it is reservoir quality.

5. Most geological risks are much reduced after a borehole is drilled. The remaining most significant risk is probably reservoir compartmentalization.

6. CO_2 storage aquifers are expected to be larger than many hydrocarbon fields, and involve factors that are of only secondary importance in the case of hydrocarbon exploration. The geological risk of drilling to locate a CO_2 storage reservoir may hence be generally higher than estimated using data from hydrocarbon exploration.

ACKNOWLEDGEMENTS

The authors would like to gratefully acknowledge the China Scholarship Council for funding Xia's doctoral study. We also thank the UK Department of Energy & Climate Change and the oil companies who make the relinquishment reports public. The two anonymous reviewers of this paper are greatly thanked for their valuable comments and advice.

References

Bachu, S., 2008. Comparison between methodologies recommended for estimation of CO2 storage capacity in geological media. Carbon Sequestration Leadersh. Forum.

Bachu, S., Bonijoly, D., Bradshaw, J., Burruss, R., Holloway, S., Christensen, N.P., Mathiassen, O.M., 2007. CO2 storage capacity estimation: Methodology and gaps. Int. J. Greenh. Gas Control 1, 430–443. doi:10.1016/S1750-5836(07)00086-2

Besly, B.., 1998. Carboniferous, in: Glennie, K.W. (Ed.), Petroleum Geology of the North Sea: Basic Concepts and Recent Advances, Fourth Edition. Blackwell Science Ltd, pp. 104–136.

Brennand, T.P., Van Hoorn, B., James, K.H., Glennie, K.W., 1998. Historical review of north sea exploration, in: Petroleum Geology of the North Sea: Basic Concepts and Recent Advances: Fourth Edition. pp. 1–41. doi:10.1002/9781444313413.ch1

Brzozowska, J., Eriksen, S., Holm, L., Olsen, S., 2003. Exploration history, in: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. The Geological Society of London, London, pp. 341–343.

Busch, A., Amann-Hildenbrand, A., Bertier, P., Waschbuesch, M., Krooss, B.M., 2010. The Significance of Caprock Sealing Integrity for CO2 Storage, in: SPE International Conference on CO2 Capture, Storage, and Utilization. Society of Petroleum Engineers. doi:10.2118/139588-MS

Chadwick, A., Arts, A., Bernstone, C., May, F., Thibeau, S. & Zweigel, P., 2008. Best practice for the storage of CO_2 in saline aquifers, Brisitsh Geological Survey occasional publication 14.

Chopra, S., Castagna, J., Portniaguine, O., 2006. Seismic resolution and thin-bed reflectivity inversion. CSEG Rec. 31, 19–25. doi:doi:10.1190/1.2369941

Cooper, C., Wright, I., Ringrose, P., Simone, A., Crow, W., Gardner, C., Williams, C., Limb, H.G., Nevels, H., Young, A., Dodds, K., McKnight, R., Imbus, S., Rennie, S., 2009. A Technical Basis for Carbon Dioxide Storage, CPL Press.

Downey, M.W., 1984. Evaluating Seals for Hydrocarbon Accumulations. Am. Assoc. Pet. Geol. Bull. 68, 1752–1763.

Eiken, O., Ringrose, P., Hermanrud, C., Nazarian, B., Torp, T.A., Høier, L., 2011. Lessons learned from 14 years of CCS operations: Sleipner, In Salah and Snøhvit. Energy Procedia 4, 5541–5548. doi:10.1016/j.egypro.2011.02.541

Eriksen, S.H., Anderson, J.H., Grist, M., Stoker, S., Brzozowska, J., 2003. Oil and gas resources, in: Evans, D., Graham, C., Armour, A., Bathurst, P. (Eds.), The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. The Geological Society of London, London, pp. 345–358.

Gainski, M., Macgregor, A.G., Freeman, P.J., Nieuwland, H.F., 2010. Turbidite reservoir compartmentalization and well targeting with 4D seismic and production data: Schiehallion Field, UK. Reserv. Compart. 347, 89–102. doi:10.1144/sp347.7

Glennie, K.W., 1998. Lower Permian - Rotliegend, in: Petroleum Geology of the North Sea: Basic Concepts and Recent Advances: Fourth Edition. pp. 137–173.

doi:10.1002/9781444313413.ch5

Glennie, K.W., 1997. Recent advances in understanding the southern North Sea basin: a summary, in: Petroleum Geology of the Southern North Sea: Future Potential, Geol. Soc. Sp. Publ. No. 123. pp. 17–30.

Glennie, K.W., Underhill, J.R., 1998. Origin, development and evolution of structural styles, in: Petroleum Geology of the North Sea: Basic Concepts and Recent Advances, Fourth Edition. pp. 42–84.

Gluyas, J., Hichens, H., 2003. United Kingdom oil and gas fields: commemorative millennium volume, Appendix 1. Geol. Soc. London, Mem. 20, 947–977.

Gray, J., 2013. Petroleum prospectivity of the principal sedimentary basins on the United Kingdom Continental Shelf Petroleum prospectivity of the principal sedimentary basins on the United Kingdom Continental Shelf 41.

Heinemann, N., Wilkinson, M., Pickup, G.E., Haszeldine, R.S., Cutler, N.A., 2012. CO2 storage in the offshore UK Bunter Sandstone Formation. Int. J. Greenh. Gas Control 6, 210–219. doi:10.1016/j.ijggc.2011.11.002

Holloway, S., Vincent, C.J., Bentham, M.B., Kirk, K.L., 2006a. Top-down and bottom-up estimates of CO2 storage capacity in the United Kingdom sector of the southern North Sea basin. Environ. Geosci. 13, 71–84. doi:10.1306/eg.11080505015

Holloway, S., Vincent, C.J., Kirk, K.L., 2006b. Industrial carbon dioxide emissions and carbon dioxide storage potential in the UK, Sustainable and renewable eneergy programme commercial report. Keyworth, Norttingham.

Howell, J.A., Flint, S.S., Hunt, C., 1996. Sedimentological aspects of the Humber Group (Upper Jurassic) of the South Central Graben, UK North Sea. Sedimentology 43, 89–114. doi:10.1111/j.1365-3091.1996.tb01462.x

Jolley, S.J., Fisher, Q.J., Ainsworth, R.B., 2010. Reservoir compartmentalization: an introduction. Reserv. Compart. 347, NP. doi:10.1144/sp347.0\r10.1144/sp347.1

Ketter, F.J., 1991. The Esmond, Forbes and Gordon Fields, Block 43/8a, 48/13a, 48/15a, 48/20a, UK. North Sea, in: United Kingdom Oil and Gas Fields 25 Years Commemorative Volume. pp. 425–432.

Loizou, N., 2014. Success in exploring for reliable, robust Paleocene traps west of Shetland. Geol. Soc. London, Spec. Publ. 397, 59–79. doi:10.1144/SP397.9

Lu, J., Wilkinson, M., Haszeldine, R.S., Fallick, A.E., 2009. Long-term performance of a mudrock seal in natural CO2 storage. Geology 37, 35–38. doi:10.1130/G25412A.1

Marchand, A.M.E., Haszeldine, R.S., Macaulay, C.I., Swennen, R., Fallick, A.E., 2000. Quartz cementation inhibited by crestal oil charge: Miller deep water sandstone, UK North Sea. Clay Miner. 35, 201–210.

Munns, J.W., Gray, J.C., Stoker, S.J., Andrews, I.J., Cameron, T.D.J., 2005. The remaining hydrocarbon potential of the UK Continental Shelf. Pet. Geol. North-West Eur. Glob. Perspect. – Proc. 6th Pet. Geol. Conf. 41–54. doi:10.1144/0060041

Ofstad, K., Kullerud, L., Helliksen, D., 2000. Evaluation of Norwegian Wildcat Wells (Article 1). Nor. Pet. Soc. Spec. Publ. 9, 23–31. doi:10.1016/S0928-8937(00)80006-5

Richards, P.C., Lott, G.K., Johnson, H., Knox, R.W., 1993. Jurassic of the central and northern North Sea. Knox, RW O'B. Cordey, WG Lithostratigr. Nomencl. UK North Sea 3, 219.

Ringrose, P.S., Mathieson, A.S., Wright, I.W., Selama, F., Hansen, O., Bissell, R., Saoula, N., Midgley, J., 2013. The In Salah CO2 Storage Project: Lessons Learned and Knowledge Transfer. Energy Procedia 37, 6226–6236. doi:10.1016/j.egypro.2013.06.551

Scott, E.D., Gelin, F., Jolley, S.J., Leenaarts, E., Sadler, S.P., Elsinger, R.J., 2010. Sedimentological control of fluid flow in deep marine turbidite reservoirs: Pierce Field, UK Central North Sea. Geol. Soc. London, Spec. Publ. 347, 113–132. doi:10.1144/SP347.9

Senior, B., 2010. CO2 Storage in the UK - Industry Potential, UK Department of Energy and Climate Change. London.

Smalley, P., England, W., Rabaa, A.W.M., 1994. Reservoir Compartmentalization Assessed With Fluid Compositional Data. SPE Reserv. Eng. 9, 175–180. doi:10.2118/25005-PA

Smalley, P.C., Hale, N.A., 1996. Early Identification of Reservoir Compartmentalization by Combining a Range of Conventional and Novel Data Types. SPE Form. Eval. 11, 163–170. doi:10.2118/30533-PA

Smith, M.M., Sholokhova, Y., Hao, Y., Carroll, S.A., 2013. Evaporite caprock integrity: An experimental study of reactive mineralogy and pore-scale heterogeneity during brine-CO2 exposure. Environ. Sci. Technol. 47, 262–268. doi:10.1021/es3012723

Stewart, D.J., 1986. Diagenesis of the shallow marine Fulmar Formation in the central North Sea. Clay Miner. 21, 537–564.

Van Hulten, F.F.N., 2010. Geological factors effecting compartmentalization of Rotliegend gas fields in the Netherlands. Reserv. Comparmentalization 347, 301–315. doi:10.1144/sp347.17

Wallis, S., 2013. Binomial Confidence Intervals and Contingency Tests: Mathematical Fundamentals and the Evaluation of Alternative Methods. Dx.Doi.Org 20, 178–208. doi:10.1080/09296174.2013.799918

Wilkinson, M., Haszeldine, R.S., 2011. Oil charge preserves exceptional porosity in deeply buried, overpressured, sandstones: Central North Sea, UK. J. Geol. Soc. London. 168, 1285–1295. doi:10.1144/0016-76492011-007

Worden, R.H., Oxtoby, N.H., Smalley, P.C., 1998. Can oil emplacement prevent quartz cementation in sandstones? Pet. Geosci. 4, 129–137. doi:10.1144/petgeo.4.2.129

Table 1 – The overall geological risks of the hydrocarbon reservoirs on the UK Continental Shelf

	Geological risks	Frequency	P_{risk} (%)	Uncertainty (%)	**P_{avoid} (%)**	**Uncertainty (%)**
Reservoir	No/poor reservoir development	94.5	27	4	**81**	**3**
	Low-porosity and/or low-permeability	78	22	4	**84**	**3**
	Reservoir compartmentalization	27	8	3	**95**	**2**
	High uncertainty concerning the lateral variation of reservoir quality	7	2	1	**99**	**1**
Trap	Incorrect trap geometry and extent prediction	78.5	23	4	**84**	**3**
	Incorrect trap depth prediction	22	6	2	**96**	**2**
Seal	Failed caprock sealing	24	7	2	**95**	**2**
	Failed bottom/lateral lithological sealing	11	3	2	**98**	**1**
	Failed bounding-fault sealing	36.5	11	3	**93**	**2**

Table 2 – Causes of geological risk

<table>
<thead>
<tr><th colspan="2">Geological risks</th><th>Possible geological causes</th><th>Possible technical causes</th></tr>
</thead>
<tbody>
<tr><td rowspan="4">Reservoir</td><td>No/poor reservoir development</td><td>• Non-deposition
• Erosion
• Interbedding with high volume of shales
• Moved apart by faulting
• Salt piercement</td><td>• Reservoir thickness below the seismic resolution
• Application of improper reservoir sedimentary model
• Poor quality of seismic data
• Misled by false seismic AVO responses or high-amplitudes that are not caused by hydrocarbon presence</td></tr>
<tr><td>Low-porosity and/or low-permeability</td><td>• High volume of ductile detrital components, in particular clay minerals
• Low degree of sorting
• Quartz cementation
• Illite growth</td><td>• Application of improper reservoir quality prediction model, or choosing of improper input parameters</td></tr>
<tr><td>Reservoir compartmentalization</td><td>• Variation of sedimentary facies
• Cemented fractures
• Sealed faults
• Highly-cemented beds (e.g. carbonate concretions)</td><td>• Insufficient or false interpretation of reservoir fluid and pressure data</td></tr>
<tr><td>High uncertainty concerning the lateral variation of reservoir quality</td><td></td><td>• False prediction of the sedimentary faices of reservoir rocks. (often occurs when the properties of reservoirs are different from pre-drill predictions)</td></tr>
<tr><td rowspan="2">Trap</td><td>Incorrect trap geometry and extent prediction</td><td>• Basin uplift causing high variation of seismic velocity in the overburden successions
• Unexpected presence of high velocity units in the shallow burden, e.g. igneous intrusions and salts
• Presence of strong velocity-contrast surfaces impairing the quality of seismic data, such as some fault planes
• Small reservoir thickness</td><td>• False picking of seismic reflectors
• Application of inaccurate rock velocity model
• False calculation of the dipping angles of reservoir-bounding faults
• Poor quality of seismic data</td></tr>
<tr><td>Incorrect trap depth prediction</td><td>• Basin uplift causing high variation of seismic velocity in the overburden successions
• Unexpected presence of high velocity units in the shallow burden, e.g. igneous intrusions and salts</td><td>• False picking of seismic reflectors
• Application of inaccurate rock velocity model
• Poor quality of seismic data</td></tr>
</tbody>
</table>

Seal	Failed caprock sealing	• Erosion of caprocks • Non-deposition • Faulting and/or fracturing of caprocks by salt flow, basin inversion or fault movement • Faulting and/or fracturing due to overpressure leak-off • Sand-prone of caprocks • Flow of caprock (only for evaporite caprocks)	• Inaccurate thickness prediction of seal rock unit • False interpretation of seal rock on seismic image • Underestimating of the possibility of fracturing/faulting on basis of the deformation degree of seal rocks
	Failed bottom/lateral lithological sealing	• Sand-prone of seal rocks • Lack of trapping geometry	• Unable to precisely determine sandstone-shale contacts
	Failed bounding-fault sealing	The sealing process of faults is complex, which is a combined function of grain fracturing, clay smear, pressure solution and cementation. Lack of these process could make permeable faults. Fault reactivation can cause additional risks to fault seals.	• Application of improper fault seal prediction model, or wrong input parameters

Table 2 – Sealing risks by trap style. The calculations of POS and its uncertainty follow Eqn. 3 and the data are from Table 1.

	Failed sealing component	Frequency	P_{risk} (%)	Uncertainty (%)	P_{avoid} (%)	Uncertainty (%)	POS (%)	Uncertainty (%)
Periclinal trap (n = 88)	Caprock	12.5	14	6	**90**	**4**	49	8
	Bottom/lateral seal	0	0	0	100	0		
	Bounding-fault	0	0	0	100	0		
Fault-bounding trap (n = 137)	Caprock	7.5	5	3	96	2	45	8
	Bottom/lateral seal	0	0	0	100	0		
	Bounding-fault	33.5	24	6	**82**	**4**		
Stratigraphic / structural-stratigraphic combination trap (n = 46)	Caprock	0.5	1	3	99	3	36	10
	Bottom/lateral seal	11.5	25	11	**74**	**10**		
	Bounding-fault	1.5	3	4	100	0		

Table 3 – The geological risks of the main reservoir units of different age in the UKCS

Geological risks		Palaeogene turbidite sandstone reservoirs					Cretaceous-Jurassic turbidite sandstone reservoirs				
		Frequency	P_{risk}	σ	$\mathbf{P_{avoid}}$	**σ**	Frequency	P_{risk}	σ	$\mathbf{P_{avoid}}$	**σ**
Reservoir	No/poor reservoir development	14.5	34%	14%	**76%**	**10%**	25	34%	11%	**76%**	**8%**
	Low-porosity and/or low-permeability	3	7%	8%	**95%**	**5%**	13	18%	9%	**88%**	**6%**
	Reservoir compartmentalization	0	0%	0%	**100%**	**0%**	2	3%	4%	**98%**	**3%**
	High uncertainty concerning the lateral variation of reservoir quality	0	0%	0%	**100%**	**0%**	4	6%	5%	**96%**	**4%**
Trap	Incorrect trap geometry and extent prediction	9.5	22%	12%	**85%**	**9%**	19	26%	10%	**82%**	**7%**
	Incorrect trap depth prediction	4	9%	9%	**94%**	**6%**	0	0%	0%	**100%**	**0%**
Seal	Failed caprock sealing	5	12%	10%	**92%**	**7%**	5	7%	6%	**95%**	**4%**
	Failed bottom/lateral lithological sealing	2.5	6%	7%	**96%**	**5%**	4	6%	5%	**96%**	**4%**
	Failed bounding-fault sealing	0.5	1%	3%	**99%**	**2%**	5	7%	6%	**95%**	**4%**
		Total number of well = 43					Total number of well = 73				

Table 4 – Continued

Upper Jurassic Fulmar shallow marine sandstone reservoirs					**Triassic fluvial-deltaic reservoirs**					**Lower Permian Rotliegend aeolian reservoirs**				
Frequency	P_{risk}	σ	$\mathbf{P_{avoid}}$	**σ**	Frequency	P_{risk}	σ	$\mathbf{P_{avoid}}$	**σ**	Frequency	P_{risk}	σ	$\mathbf{P_{avoid}}$	**σ**
33	49%	10%	**66%**	**7%**	5	16%	11%	**89%**	**8%**	4	7%	5%	**96%**	**6%**
4	6%	5%	**96%**	**3%**	4	13%	10%	**91%**	**7%**	22	36%	10%	**75%**	**3%**
7	10%	6%	**93%**	**4%**	2	7%	7%	**96%**	**5%**	1	2%	3%	**99%**	**4%**
0	0%	0%	**100%**	**0%**	0	0%	0%	**100%**	**0%**	0	0%	0%	**100%**	**7%**
12.5	19%	8%	**87%**	**5%**	8	26%	13%	**82%**	**9%**	12.5	20%	8%	**86%**	**2%**
0	0%	0%	**100%**	**0%**	6	19%	12%	**87%**	**8%**	8	13%	7%	**91%**	**0%**
6.5	10%	6%	**93%**	**4%**	2	7%	7%	**96%**	**5%**	5.5	9%	6%	**94%**	**6%**
3.5	5%	4%	**96%**	**3%**	0	0%	0%	**100%**	**0%**	0.5	1%	2%	**99%**	**5%**
8	12%	7%	**92%**	**5%**	6	19%	12%	**87%**	**8%**	12	19%	8%	**87%**	**4%**
Total number of well = 67					Total number of well = 31					Total number of well = 62				

Table 4 – Continued

Carboniferous fluvial reservoirs				
Frequency	P_{risk}	σ	$\mathbf{P_{avoid}}$	**σ**
4	9%	7%	**94%**	**6%**
24	52%	12%	**64%**	**5%**
8	17%	9%	**88%**	**9%**
2	4%	5%	**97%**	**6%**
10	22%	10%	**85%**	**4%**
4	9%	7%	**94%**	**7%**
0.5	1%	3%	**99%**	**5%**
1	2%	4%	**99%**	**2%**
1	2%	4%	**99%**	**3%**
Total number of well = 46				

Table 4. The probability of success for reservoirs of different age in periclinal traps

	Probability of success (%)	**90% confidence interval**
All ages	49	8
Paleogene turbidites	53	23
Cretaceous-Jurassic turbidites	49	18
Upper Jurassic shallow marine	47	14
Triassic fluvial-deltic	52	25
Lower Permian aeolian	52	15
Carboniferous fluvial-deltaic	40	19